THE ROLE OF WIND GENERATION IN ENHANCING SCOTLAND’S ENERGY DIVERSITY AND SECURITY:
A MEAN-VARIANCE PORTFOLIO OPTIMIZATION OF SCOTLAND’S GENERATING MIX

VOLUME II: DETAILED ANALYSIS AND CONCLUSIONS

By

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Abstract

The UK Energy White Paper sets targets for decarbonization and the deployment of wind and other renewable electricity generating alternatives. The Scottish Executive is committed to increasing renewable energy shares and has set explicit targets in order to progress on the White Paper objectives. Fossil fuel independence, reliance on domestic sources and enhanced energy security are been additional motivating factors for these objectives.

Much to its credit, The Scottish Executive is pushing forward on the adoption of wind and other renewables in spite of the widespread belief that these technologies cost more and that increasing their share of the generating mix must therefore increase overall generating costs. The Executive’s efforts are especially notable since risk and other externalities, as subsequently discussed, will tend to drive market participants to over-invest in fossil technologies relative to wind. The idea that a more costly technology in the mix must raise overall generating cost seems obvious and compelling. Nonetheless, it is flawed.

Estimating the overall cost of a given generating mix involves assessing long-term future cost expectations for highly uncertain fossil fuel and other outlays that have fluctuated significantly and unpredictably in the past. In other words, generating cost estimates reflect an assessment of how cost will behave in the distant future, 10 or 20 years from now. Highly uncertain long-term costs cannot be directly observed or calculated the way cost is calculated for a bundle of fresh fruit at the market.

Energy planning represents an investment-decision problem. Investors commonly evaluate such problems using portfolio theory to manage risk and maximize portfolio performance under a variety of unpredictable economic outcomes. Energy policy makers need to similarly abandon their reliance on traditional, “least-cost” stand-alone generating cost estimates and instead evaluate conventional and renewable energy sources on the basis of their portfolio cost— their cost contribution relative to their risk contribution to a mix of generating assets.

This report describes essential portfolio-theory ideas and discusses their application to the Scotland electricity generating mix. The report illustrates how wind and other renewables improve the Scottish generating mix. Compared to fossil-dominated mixes, efficient generating portfolios include greater wind shares, thereby enhancing energy security. Such efficient portfolios also reduce generating cost. Though counter-intuitive, the idea that adding more costly wind can actually reduce portfolio-generating cost is consistent with basic finance theory. An important implication is that in dynamic and uncertain environments, the relative value of generating technologies must be determined not by evaluating alternative resources, but by evaluating alternative resource portfolios. The optimal results presented in this analysis indicate that compared to National Grid projected mixes, there exist generating mixes with larger on- and off-shore wind shares at equal or lower expected cost and risk.
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1. “LEAST-COST” VERSUS PORTFOLIO-BASED APPROACHES IN GENERATION PLANNING

Wind and other renewables provide clean generating alternatives, and hence offer effective mechanisms to help climate change mitigation but policy makers are concerned because of the widespread perception that increasing their deployment will raise the overall cost of generating electricity.

In the UK, Electricity policy and capacity planning is largely based on least-cost principles, under which planners evaluate generating alternatives using their stand-alone costs. Least-cost may have worked sufficiently well in previous technological eras, marked by relative cost certainty, low rates of technological progress, technologically homogeneous generating alternatives and stable energy prices [Awerbuch, 1995a]. Today’s electricity planner faces a broadly diverse range of resource options and a dynamic, complex, and uncertain future. Attempting to identify least-cost alternatives in this environment is virtually impossible [Awerbuch, 1996].

Financial asset portfolio provides the best means of hedging future risk and therefore evaluate individual investments in terms of their portfolio effects. Given today’s uncertainty about future technology cost and performance, it makes sense to also shift electricity planning from its current emphasis of evaluating alternative technologies, to evaluating alternative generating portfolios and strategies. Mean-variance portfolio (MVP) theory is highly suited to the problem of planning and evaluating Scotland’s electricity generating portfolio.

MVP principles evaluate conventional and renewable alternatives not on the basis of their stand-alone cost, but on the basis of their portfolio cost—i.e.: their contribution to overall portfolio generating cost relative to their contribution to overall portfolio risk. At any given

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1 In the US, utility planning is conducted using Integrated Resource Planning procedures and IRP filings increasingly claim to use a “portfolio approach” (e.g.: Pacificorp 2003 Integrated Resource Plan, http://www.pacificorp.com/File/File25682.pdf). However, while these filings evaluate alternative sets of arbitrarily constructed expansion portfolios, they do not incorporate the important mean-variance portfolio risk elements described here. Rather, they perform the traditional sensitivity-based risk analyses, which can be quite misleading as I have discussed elsewhere (e.g. Awerbuch 1993, 1995, 1995a).

2 MVP, an established part of modern finance theory, is based on the pioneering work of Nobel Laureate Harry Markowitz 50 years ago (Fabozzi, Gupta and Markowitz [2002] and Varian [1993]). In addition to its widespread use for financial portfolio optimization, MVP has been applied to capital budgeting and project valuation [Seitz and Ellison, 1995], valuing offshore oil leases [Helfat, 1988], energy planning [Krey and Zweifel, 2005; Awerbuch and Berger 2003; Berger 2003; Awerbuch 2000a, Humphreys and McLain 1998, Awerbuch 1995, Bar-Lev and Katz 1976] quantifying climate change mitigation risks [Springer, 2003, Springer and Laurikka (undated)] and optimizing real (physical) and derivative electricity trading options [Kleindorfer and Li 2005].
time, some alternatives in the portfolio may have higher costs while others have lower costs, yet over time, the astute combination of resources serves to minimize overall expected generation cost relative to the risk.

This report describes a portfolio-based analysis that examines the effect of increasing the share of wind generation in Scotland. The analysis suggests that Scotland’s electricity-generating mix will benefit from additional wind shares, even under the assumption that it costs more than other alternatives on a stand-alone basis.

Although counter-intuitive, the idea that adding more costly wind can actually reduce portfolio-generating cost is consistent with basic finance theory and derives from the statistical independence of wind costs, which do not correlate (or covary) with fossil price movements. Adding wind increases portfolio diversification and yields lower expected generating costs.

**Portfolio-Based Planning For Electricity Generation**

Portfolio optimization locates generating mixes with lowest-expected cost at every level of risk, where risk is defined in the usual finance fashion as the year-to-year variability (standard deviation) of technology generating costs. The target generating mix for the year 2010, developed by the National Grid Company (NGC), serves as a benchmark or starting point for the analysis. The optimized results indicate that it is possible to improve on the risk-cost properties of the target mix, i.e.: that there exist other mixes with larger wind shares that exhibit equal or lower cost and risk.

Portfolio theory was initially conceived in the context of financial portfolios, where it relates $E(r_p)$, the expected portfolio return, to $\sigma_p$, the total portfolio risk, defined as the standard deviation of periodic portfolio returns. The following discussion of portfolio theory is based on a simple, two-asset portfolio, presented in the context of portfolio cost, which can be interpreted as the inverse of return.

Portfolio Optimization locates minimum cost generating portfolios at every level of risk. These optimal or efficient mixes lie along the Efficient Frontier (EF). Portfolio cost is the weighted average cost of the generating mix components. For a two-technology generating mix, expected portfolio cost is the weighted average of the individual expected costs of the two technologies:

$$\text{Expected Portfolio Cost} = E(C_p) = X_1 \cdot E(C_1) + X_2 \cdot E(C_2) \quad \text{(Eq. 1)}$$

Where: $X_1$, $X_2$ are the proportional shares of the two technologies in the mix and $E(C_1)$ and $E(C_2)$ are their expected generating costs.

---

3 See: Brealey and Myers, McGraw Hill or any other finance text.
Expected Portfolio risk, $\sigma_p$, is also a weighted average of the individual technology cost variances, as tempered by their co-variances:

$$\text{Expected Portfolio risk} = \sigma_p = \sqrt{X_1^2 \sigma_1^2 + X_2^2 \sigma_2^2 + 2 X_1 X_2 \rho_{12} \sigma_1 \sigma_2} \quad \text{(Eq. 2)}$$

Where:
- $X_1$ and $X_2$ are the proportional shares of the two technologies in the mix
- $\sigma_1$ and $\sigma_2$ are the standard deviations of the holding period returns (HPR)$^4$ of the annual costs of technologies $1$ and $2$
- $\rho_{12}$ is their correlation coefficient

This leads to the following technology risk estimates (Table 1), where the standard deviations apply to the HPRs. For example, in the case of natural gas fuel price, the standard deviation is $\sigma = 23\%$. This is the standard deviation of the annual HPRs (the year-to-year rates of change). In the case of Renewable technologies, which require no fuel outlays, the standard deviation for fuel is zero.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Construction Period</th>
<th>Fuel</th>
<th>Variable O&amp;M</th>
<th>Fixed O&amp;M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>10.0%</td>
<td>23.0%</td>
<td>20.0%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Coal</td>
<td>20.0%</td>
<td>12.8%</td>
<td>20.0%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>20.0%</td>
<td>9.5%</td>
<td>20.0%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Hydro</td>
<td>20.0%</td>
<td>--</td>
<td>20.0%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Onshore Wind</td>
<td>5.0%</td>
<td>--</td>
<td>20.0%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Offshore Wind</td>
<td>7.5%</td>
<td>--</td>
<td>20.0%</td>
<td>8.7%</td>
</tr>
</tbody>
</table>

b. Construction period risk for existing (embedded) technologies is 0.0
c. Empirically estimated from UK price data

Construction period risks vary by technology type and are generally related to complexity and length of the construction period. Wind and gas project risk is estimated from interviews with developers. Coal plant construction risk is set equal to the standard deviation of a diversified financial portfolio, as is variable O&M risk for all technologies.

$^4$ The Holding Period Return is defined as $\text{HPR} = (EV - BV)/BV$, where $EV$ is the ending value and $BV$ the beginning value, e.g. see: Seitz and Ellison, (1995), Brealey and Myers, (2004) or any finance text. A detailed discussion of its relevance to portfolios is given in Awerbuch and Berger (2003).
Fixed O&M risk is estimated using a financial proxy. Fixed O&M implies an annual obligation that will be undertaken by the project owner as long as sufficient income exists, which makes this risk similar to the risk of payments on the firm’s debt. Fixed O&M is therefore a debt-equivalent obligation (e.g., Brealey and Myers) whose year-to-year standard deviation is approximated by the standard deviation of an investment grade bond (Awerbuch and Berger, 2003). As a result the percent standard deviation for this risk are the same for all technologies. This does not mean that the level of O&M is the same—it merely suggests that systematic year-to-year fluctuations are constant. Sensitivity analysis suggests that optimal portfolio results are relatively insensitive to the O&M and construction period risk estimates (Awerbuch and Berger, 2003, Berger 2004).

The correlation coefficient, $\rho$, is a measure of diversity. Lower correlation among portfolio components creates greater diversity, which serves to reduce portfolio risk. More generally, portfolio risk falls with increasing diversity, as measured by an absence of correlation (covariance) between portfolio components. Adding a fixed-cost technology to a risky generating mix serves to lower expected portfolio cost at any level of risk, even if the fixed-cost technology costs more (Awerbuch, 2005). A pure fixed-cost technology, has $\sigma_i = 0$. This lowers portfolio risk (since two terms in Equation 2 reduce to zero), which in turn allows other higher-risk/lowercost technologies into the optimal mix. In the case of fuel-less renewable technologies, fuel risk is zero and its correlation with fossil fuel costs is also taken as zero.

Portfolio optimization locates generating mixes with minimum expected cost and year-to-year risk. For each technology, risk is the year-to-year standard deviation of the HPRs for three generating cost inputs: fuel, O&M and capital or construction period risk. Fossil fuel standard deviations are estimated from historic UK data. Standard deviations for capital and O&M are estimated using proxy procedures as discussed above. Construction period risk for embedded technologies is 0.0. ‘New’ technologies are therefore riskier than embedded ones—e.g., new coal is riskier than ‘old’ coal. New technologies are often more efficient than older ones or have lower capital costs per MW of capacity. ‘New’ technologies, especially in the case of wind and gas, therefore exhibit lower kWh costs.

This study assumes full capital recovery for embedded technologies. Even though capital costs are sunk from an economic perspective, our study assumes that generators will set prices so they can expect to recover their sunk costs. This assumption may not hold in day-

<table>
<thead>
<tr>
<th>UK Historic Fuel Price Correlations ( $\rho$ )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
</tr>
<tr>
<td>Coal</td>
</tr>
<tr>
<td>Gas</td>
</tr>
<tr>
<td>Nuclear</td>
</tr>
<tr>
<td>Renewable</td>
</tr>
</tbody>
</table>

5 Note that for a fixed-cost technology $\sigma_i = 0$ or nearly so. This reduces $\sigma_p$, since two of the three terms in Equation 2 are reduced to zero. It is also easy to see that $\rho$ declines as $\sigma_i$ falls below 1.0.

6 For example, standard deviation of annual natural gas price HPR’s over the last 10 years is 0.23
to-day decision-making, where a particular generator may bid its power into the system even if it can expect to recover only its running costs. Over time however, that generator cannot remain viable without also recovering its capital costs. Full-cost recovery therefore appears to be the appropriate approach for both embedded and new plant.

The portfolio analysis focuses on the risk of generating costs. Future fossil fuel and other outlays are random statistical variables. While their historic averages and standard deviations are known, they move unpredictably over time. No one knows for sure what the price of gas will be next month, just like nobody knows what the stock markets will do. Estimating the generating cost of a particular portfolio presents the same problems as estimating the expected return to a financial portfolio. It involves estimating cost from the perspective of its market risk.

The cost structures of wind and similar capital-intensive renewable technologies are essentially fixed or riskless over time. Perhaps more important is the fact that the costs of wind generation are uncorrelated to fossil price risk. This helps diversify the generating mix and enhance its cost-risk performance. The operating costs of a generating mix containing 30% wind will fluctuate a lot less year-to-year than one with no wind.

The portfolio analysis generally reflects all relevant risk. This does not mean that every risk possibility, even if it could be enumerated, is measured and accounted for. In a generating portfolio, random (unsystematic) risk is diversified away and hence does not contribute to overall portfolio risk. For example, year-to-year fluctuations in electricity output of a wind farm—an unsystematic risk—is not relevant for portfolio purposes since it is uncorrelated to the risk of other portfolio cost streams. The same would hold for annual variations attained fuel conversion efficiency at a gas turbine. In spite of the fact that such yearly changes might change the accountant’s estimate of kWh generating costs at a given site hence representing a risk to the owners, that risk is diversified in a portfolio and does not affect overall portfolio risk.

Annual wind resource variability is likely random and uncorrelated to economic activity or to other portfolio generating costs. While it is possible to measure the standard deviation of the yearly wind resource at a given location, its correlation to other costs is zero (i.e. $t_2 = 0$).

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7 Although there is evidence that these movements are not uncorrelated with economic activity and with the returns to other assets (Awerbuch and Sauter, 2005, Awerbuch, 1995, 1993, Bolinger, Wiser and Golove, 2004).

8 The finance theory aspects of this idea are further developed in Awerbuch, (2000).

9 On an accounting basis, kWh generating cost is calculated by dividing annual capital charges plus operating costs by the year’s kWh output. Given a fixed capital charge and relatively fixed maintenance costs, therefore, annual wind output variability would cause year-to-year kWh costs to vary.
0). It therefore does not contribute to portfolio risk per Equation 2. In finance terms, year-to-year wind variability is an unsystematic (uncorrelated) risk, even for single wind site.\(^{10}\)

Current least cost approaches for evaluating and planning electricity generating mixes consistently bias in favour of risky fossil alternatives while understating the true value of wind, PV, geothermal and similar fixed-cost, low-risk, passive, capital-intensive technologies. The evidence indicates that such technologies offer a unique cost-risk menu along with other valuable attributes that traditional valuation models cannot “see” [Awerbuch, 1993, 1995, 1995a]. The evidence further suggests that wind and similar fixed-cost renewables cost-effectively hedge fossil price risk as compared to standard financial hedging mechanisms [Bolinger, Wiser and Golove, 2004].

**How Portfolio Theory improves Decision-making**

Portfolio optimization exploits the interrelationships (correlations) among the various technology generating costs (Equation 2). For example, because fossil price are correlated with each other, a fossil-dominated portfolio is undiversified and exposed to fuel price risk. Conversely, renewables, nuclear and other non-fossil options diversify the mix and reduce its expected risk because their costs do not correlate to fossil prices.

This so-called portfolio effect is illustrated in Figure 1, which shows the costs and risks for various possible two-technology portfolios. Technology A is representative of a higher-cost/lower-risk alternative such as wind. It has an expected (illustrative) cost of about 7.3 \(p\) per kWh with an expected risk or cost variability of 0.15.

Technology B is a lower-cost/higher-risk alternative, such as gas-based generation. Its expected cost is 4.6 \(p\)/kWh with an expected risk of 0.2. The correlation factor between the total cost streams of the two technologies is assumed to be 0.0.\(^{11}\)

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\(^{10}\) Investors can eliminate this variability by holding a portfolio of wind farms that that is sufficiently geographically dispersed.

\(^{11}\) This is a simplification since in reality the capital and operating cost risks of PV may exhibit at least some correlation to the capital and operating costs of fossil technologies.
As a consequence of the portfolio effect, total portfolio risk decreases when the riskier Technology B is added to a portfolio consisting of 100% technology A. For example, Portfolio J, which comprises 90% of Technology A plus 10% B, exhibits a lower expected risk than a portfolio comprising 100% A. Investors, in fact, would not hold any mix above Portfolio V, the minimum variance portfolio, since mixes with the same risk can be obtained at lower cost on the solid portion of the blue line. Portfolio K is therefore superior to 100% A. It has the same risk but lower expected cost. Investors would hold Mix K over 100% A. Portfolio K is also superior to a portfolio of 100% Technology B. It reduces risk by some 25% while increasing cost by only 10% (0.5p/kWh). Astute portfolio combinations of diversified alternatives therefore produce better results.
2. Scotland Portfolio: Technology Shares and Cost Inputs

Current and Projected Capacity

Figure 2 illustrates that most of the capacity growth comes from on-shore wind, which provides Scotland an opportunity to diversify its mix away from fossil. The projected Capacity Mix includes 7.4 GW of wind and hydro, (49% of total capacity, Table 3), and 5.4 GW of onshore wind (36% of total capacity). By contrast, Garrad-Hassan (2001) estimate that on-shore wind has a resource potential of 11.5 GW, about three-quarters of total capacity.

Figure 2: 2004 and Projected 2010 Scotland Capacity Mix
### Table 3: Current and Target Year Electricity Capacity and Generating Mix Details

<table>
<thead>
<tr>
<th></th>
<th>2004 Capacity Mix</th>
<th></th>
<th>2010 Target Capacity Mix</th>
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</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>GW</td>
<td>%</td>
<td>GW</td>
<td>%</td>
</tr>
<tr>
<td>CCGT</td>
<td>1.5</td>
<td>14.0%</td>
<td>1.5</td>
<td>10.1%</td>
</tr>
<tr>
<td>Gas Turbine</td>
<td>0.3</td>
<td>2.6%</td>
<td>0.3</td>
<td>1.9%</td>
</tr>
<tr>
<td>Coal</td>
<td>3.5</td>
<td>31.8%</td>
<td>3.5</td>
<td>22.9%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>2.5</td>
<td>22.9%</td>
<td>2.5</td>
<td>16.5%</td>
</tr>
<tr>
<td>Hydro</td>
<td>1.8</td>
<td>16.8%</td>
<td>1.8</td>
<td>12.1%</td>
</tr>
<tr>
<td>New hydro</td>
<td>0.0</td>
<td>0.0%</td>
<td>0.2</td>
<td>1.1%</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>1.3</td>
<td>11.9%</td>
<td>1.3</td>
<td>8.6%</td>
</tr>
<tr>
<td>New wind onshore</td>
<td>0.0</td>
<td>0.0%</td>
<td>4.1</td>
<td>27.0%</td>
</tr>
<tr>
<td>Total</td>
<td>10.9</td>
<td>100.0%</td>
<td>15.1</td>
<td>100.0%</td>
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<table>
<thead>
<tr>
<th></th>
<th>2004 Energy Mix</th>
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<th>2010 Target Energy Mix</th>
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<tr>
<td></td>
<td>TWH</td>
<td>%</td>
<td>TWH</td>
<td>%</td>
</tr>
<tr>
<td>CCGT</td>
<td>8.9</td>
<td>17.8%</td>
<td>8.9</td>
<td>14.6%</td>
</tr>
<tr>
<td>Gas Turbine</td>
<td>1.1</td>
<td>2.2%</td>
<td>1.1</td>
<td>1.8%</td>
</tr>
<tr>
<td>Coal</td>
<td>17.5</td>
<td>34.9%</td>
<td>17.5</td>
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<tr>
<td>Nuclear</td>
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<td>32.1%</td>
<td>16.2</td>
<td>26.4%</td>
</tr>
<tr>
<td>Hydro</td>
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<tr>
<td>New hydro</td>
<td>0.0</td>
<td>0.0%</td>
<td>0.3</td>
<td>0.5%</td>
</tr>
<tr>
<td>Wind onshore</td>
<td>3.4</td>
<td>6.8%</td>
<td>3.4</td>
<td>5.5%</td>
</tr>
<tr>
<td>New wind onshore</td>
<td>0.0</td>
<td>0.0%</td>
<td>10.7</td>
<td>17.5%</td>
</tr>
<tr>
<td>Total</td>
<td>50.3</td>
<td>100%</td>
<td>61.3</td>
<td>100%</td>
</tr>
</tbody>
</table>
Energy Mix

Figure 3 shows the current and projected Scotland target generating mix for the year 2010, with most of the generation growth relative to 2004 scheduled to be in the form of on-shore wind. Scottish annual demand is currently at 33TWh so that about 17 TWh is exported.

Figure 3: 2004 and Projected 2010 Scotland Generation Mix

TWH of generation in Figure 3 are estimated using historic annual Full Load Hours as estimated in Table 4 (Source: DTI and ILEX).

The projected target mix includes 18 TWH of wind and hydro (29% of total generation) and 14 TWH of onshore wind— 23% of total generation (Table 3). The Scottish Executive (2001), by contrast, has promulgated 2010 Renewables Targets of 18% of total generation, about 11 TWH, which implies about 12% on-shore wind and 6% hydro.

As discussed above, Garrad Hassan estimates total wind resource at 11.5 GW. This is sufficient to provide nearly 30 TWH— 46% of total energy generated. In the analysis, we arbitrarily constrained on-shore wind to two-thirds of this amount or 31% of total energy. In addition, we also constrained nuclear output to its 2004 levels.
## Annual UK Plant Availability Factors (%)

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<thead>
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</thead>
<tbody>
<tr>
<td>Combined cycle gas turbine</td>
<td>71.2 81.7 79.2 84.0 75.0 69.7 70.0 59.8 60.3</td>
<td>67.0</td>
<td>5866</td>
<td></td>
<td></td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Nuclear stations</td>
<td>76.5 79.1 80.1 77.5 70.5 76.1 75.1 77.8 71.0</td>
<td>74.1</td>
<td>6491</td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Hydro-electric stations:</td>
<td>24.1 28.8 36.7 38.0 37.2 27.4 33.8 22.5 37.2</td>
<td>31.6</td>
<td>2770</td>
<td></td>
<td></td>
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<tr>
<td>Natural flow</td>
<td>6.2 5.9 6.4 11.5 10.7 9.6 10.5 10.8 10.5</td>
<td>10.4</td>
<td>913</td>
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</tr>
<tr>
<td>Pumped storage</td>
<td>43.7 37.3 38.9 35.3 39.2 40.2 40.6 50.0 47.7</td>
<td>43.5</td>
<td>3814</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Conventional thermal and other */</td>
<td>57.9 50.6 43.8 50.8 56.0 55.9 65.0 62.0</td>
<td>57.9</td>
<td>5076</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>of which coal-fired stations</td>
<td>-- 48.4 50.6 43.8 50.8 56.0 55.9 65.0 62.0</td>
<td>57.9</td>
<td>5076</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*/ Conventional steam plants, gas turbines and oil engines and plants producing electricity from renewable sources other than hydro

Source: [http://www.dti.gov.uk/energy/inform/energy_stats/electricity/dukes05_5_10.xls], 1 August 2005

Table 4: UK Plant Availability

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Technology Generating Cost

Figure 4 shows the levelized generating costs for new entrants (Source: Credit Suisse-First Boston, 2005), although natural gas has price been revised from CSFB’s 27.0 p/therm to 30.3 p/therm, which better reflect recent expectations. The cost of CO2 has also been revised from CSFB’s €15/tonne to €18.6/tonne. Both natural gas and CO2 have been trading at higher prices. Finally, the CSFB new entrant costs were adjusted for capital cost and fuel efficiency to produce a set of existing generation costs for fossil and wind. Costs for off-shore wind are estimated by Airtricity.

![Figure 3: Reference Case New Entrant Generating Costs (Source: CSFB and ECN)](image-url)
Technology Cost-Risk

Figure 5 plots the CSFB kWh cost for each of the generating technologies considered in the analysis along with its risk. Risk for a given technology is determined using Equation 2, where the weights ($X_1, X_2$, etc.) are given by the proportional values of the levelized cost components, capital, fuel and O&M.

![Figure 5: 2010 Reference Case Technology Costs and Estimated Risk](image-url)
3. Portfolio Optimization of Scotland’s Generating Mix

Interpreting the Results: The CSFB Reference Case

This section summarizes the Scotland 2010 portfolio optimization using the Credit Suisse First Boston cost structures, which omit system integration costs. The analysis compares the risk-return properties of the projected NGC target generating mix to a set of optimal portfolios that minimize cost and risk, and generally include larger wind shares. Adding wind capacity does not necessarily raise cost, even if it believed that it costs more on a stand-alone basis.

The charts accompanying the discussion show the portfolio generating cost and risk for each analysis. The Efficient Frontier (pink line) is the location of all optimal mixes. Mixes lying above the EF are inefficient (sub-optimal) since expected cost and risk can both be improved (Figure 6). Along the EF, cost reductions can be achieved only by accepting generating mixes with greater risk. There exist no feasible solutions below the EF. An infinite number of generating mixes exist on each chart, although we locate and show only a small set of typical mixes.

Figure 6 shows the optimized cost-risk results for the 2010 CSFB Reference Case. It identifies a number of typical mixes that are superior to the NGC Target mix. An infinite number of other such mixes exist, and could be located, given additional conditions and optimization constraints. Typical mixes are defined below and illustrated with respect to Figure 6.

© Shimon Awerbuch, December, 2005
a. **Target Year Mix:** in this case developed by NGC.

b. **Mix P - High-cost Mix:** This is the feasible optimal generating mix with the highest-cost and lowest-risk for the particular set of conditions assumed. It is usually the most diverse (e.g. see: Stirling, 1996).

c. **Mix N - Equal-cost Mix:** This is the *Minimum-risk* mix whose cost equals that of the Target NGC-2010 mix.

d. **Mix S - Equal-risk mix:** This is the Minimum-cost mix whose risk equals that of the Target NGC-2010 mix.

e. **Mix Q: Low-cost Mix:** This is the lowest-cost, highest-risk feasible optimal mix. It is usually the least diverse and often consists primarily of gas generation.

<table>
<thead>
<tr>
<th>Value of Typical Mixes in CSFB Reference Case (Figure 6)</th>
<th>Cost /MWH</th>
<th>Wind share</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target-mix</td>
<td>41.40</td>
<td>23%</td>
</tr>
<tr>
<td>Mix P:</td>
<td>42.00</td>
<td>44%</td>
</tr>
<tr>
<td>Mix N:</td>
<td>41.40</td>
<td>39%</td>
</tr>
<tr>
<td>Mix S:</td>
<td>37.70</td>
<td>31%</td>
</tr>
<tr>
<td>Mix Q:</td>
<td>36.00</td>
<td>31%</td>
</tr>
</tbody>
</table>

Recall that on-shore wind is constrained to 31% of the total mix.\(^{12}\) Absent this constraint wind shares for the Reference Case would be higher. In addition to these four typical mixes, infinite other solutions exist. More importantly, radically different portfolio mixes can produce very similar risk-return characteristics. Indeed in any risk-return vicinity there will exist a large number of radically different feasible portfolio combinations. This enables the optimization to locate mixes with desired risk-return properties, but with higher wind shares.

The optimized mixes are not necessarily matched to the load duration curve, in the sense that they may not contain sufficient flexible peaking capacity. Moreover, these solutions may involve decommissioning existing plants and substituting newer, lower cost technologies. Such moves may not always occur in reality. Additional work could focus on these and other requirements, which will further constrain the optimal solution. Given the strength of these results, however, it is likely that even with further constraints, efficient solutions that meet additional system and political requirements do exist.

The Scotland portfolio optimization is illustrative. It is not a specific capacity-expansion plan. Its primary purpose is to illustrate that as long as the mix can be re-shuffled over time, adding wind and other fixed-cost technologies, whose costs are uncorrelated to the rest of the mix, has the effect of diversifying the portfolio and hence reducing its expected cost. The

\(^{12}\) Nuclear capacity is also constrained and hence remains unchanged
results show the optimal wind shares, ignoring any requirement to optimize technologies to
the load duration curve.

In deregulated environments, investment decisions are made by individual power producers
who evaluate only their own direct costs and risks, but do not reflect the effects their
technologies may have on overall portfolio performance. Wind investors, for example,
cannot capture the risk-mitigation benefits they produce for the overall portfolio. This leads
to under-investment in wind relative to levels that may be more optimal from a customer or
societal perspective.

Finally, some investors may prefer the risk menu offered by fuel-intensive technologies such
as gas–CC turbines, which have very low capital costs. Given sufficient market power, such
investors may be able to externalize fuel risks onto customers. In such cases these investors
do not bear the full risk effects they impose onto the generating mix, which may lead to
over-investment in gas relative to what is more optimal from a total portfolio perspective.

The Cost of Not Fully Exploiting Scotland’s On-shore Wind Potential

The Scottish Executive has set a 2010 renewables target of 18% of electricity generated
(Scottish Executive, 2001). Since hydro shares represent about 6% of generation, the target
implies sets a 12% goal for wind. The Scottish Executive’s 18% target aims for 11 TWH
on-shore wind. This represents 4.2 GW of the 11.5 GW total Scottish wind potential
(Garrad-Hassan, 2001). It is also less ambitious than the NGC target mix.

This section evaluates the effects of limiting the wind share in this manner. The results
suggest that failing to exploit Scotland’s wind resources significantly raises cost and risk

The results (Figure 7) suggest that lower wind shares increase risk and cost. The Reference
Case Mix N has a risk of 3.2% and a cost of 41.40/MWH (Figure 6). The cost of Mix N is
unchanged in the Scottish Executive Scenario (12% wind case), but its risk increases by
more than one-third to 4.4%. The Mix S is undefined for the Scottish Executive Case, but
the EF frontier generally shows cost differences above the reference case in the range of
10%-20% and more. The Scottish Executive targets have been evaluated relative to the
CSFB reference case, the comparison would be qualitatively unchanged if system charges
were included as discussed in the next section.
Figure 7: Effect of Scottish Executive Renewables Target: Reducing On-Shore Wind to 12% Increases Cost and Risk

Constraining wind shares to 12% from its 31% in Reference Case generally Increases cost by 10%-20% and risk by 25%-40%
Base Case: The Effect of System Integration Charges

The CSFB reference case results of the previous sections suggest that increasing wind shares do not increase cost. They also indicate that not fully utilizing Scotland’s wind resources raises both the cost and the risk of the generating mix. This section presents the System Integration Base Case, which uses the CSFB cost data, but adjusts wind-generating costs to include a 16/MWH charge that reflects system integration costs.

System integration is a complex issue and the section begins by describing mechanisms for integrating wind that do not incur additional reserves and system balancing costs. Such mechanisms may depend on new network system investments and protocols. While these may help integrate wind, wind is not the cost driver and they should not be considered as a requirement for integrating wind. Rather, such investments will enable networks to better meet a variety of market-driven 21st century needs. Since such networks are not yet in place, the System Integration Charge Base Case resorts to adding a 16/MWH cost to wind output.

Integrating Wind

Wind is a variable-output technology. Many think of it as ‘intermittent’ although there are very few times when wind output is actually zero. Wind variability has made the issue of wind integration more complex. Proposals have been made for new electricity network protocols and information systems that can help exploit wind variability and obviate the need for standby reserve capacity (e.g. Awerbuch 2004, Fox and Flynn, 2005). These proposals generally involve the idea of matching variable output wind to dispatchable or interruptible load applications. For example, wind-based electricity can be used to store thermal energy in residential and commercial heating equipment. When wind output diminishes, the process temporarily terminates, so that no system balancing or backup power is required.

Given existing electricity network organization and protocols, however, wind integration generally requires some extra level of backup capacity to balance the system when wind output is reduced. Several studies have quantified the costs of integrating wind in this manner with similar results. In this analysis we apply the results of one widely cited study conducted by Lewis Dale of National Grid and others (Dale, Milborrow, et. al. 2004).

Using “cautious assumptions,” Dale, et. al. (2004) estimate that the additional cost of 20% wind on the UK system is approximately 1.6 pence/kWh of wind produced. In the System Integration Base Case wind generation costs are increased by this amount, which yields a cost of 4.8 p/kWh for new on-shore wind and 7.6 p/kWh for offshore wind.

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## Table 5: Levelized Wind Generating Cost Components (\$/MWh)

<table>
<thead>
<tr>
<th>CSFB Reference Case and system Charge Base Case</th>
<th>Capital Outlays</th>
<th>Fixed Costs</th>
<th>Variable Costs</th>
<th>System Integration Costs</th>
<th>Total Levelized Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CSFB Reference Case</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing On-shore a/</td>
<td>33.4</td>
<td>3.4</td>
<td>2.8</td>
<td>0.0</td>
<td>£39.6</td>
</tr>
<tr>
<td>New On-shore b/</td>
<td>26.2</td>
<td>3.4</td>
<td>2.8</td>
<td>0.0</td>
<td>£32.4</td>
</tr>
<tr>
<td>Off-shore a/</td>
<td>48.5</td>
<td>6.4</td>
<td>5.1</td>
<td>0.0</td>
<td>£60.0</td>
</tr>
<tr>
<td><strong>System Charge Base Case</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing On-shore a/</td>
<td>33.4</td>
<td>3.4</td>
<td>2.8</td>
<td>16.0</td>
<td>£55.6</td>
</tr>
<tr>
<td>New On-shore b/</td>
<td>26.2</td>
<td>3.4</td>
<td>2.8</td>
<td>16.0</td>
<td>£48.4</td>
</tr>
<tr>
<td>Off-shore a/</td>
<td>48.5</td>
<td>6.4</td>
<td>5.1</td>
<td>16.0</td>
<td>£76.0</td>
</tr>
</tbody>
</table>

a. Estimates by ECN and Airtricity
b. CSFB Estimates

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Figure 8: Base Case Technology Costs (Includes System Charges)
Base Case Results

Figure 9 gives the technology costs for the System Integration Base Case, showing how the system integration charge affects the costs of wind generation. Figure 10 shows the resulting cost-risk. When system integration costs are included, The Target Mix Costs £45.10, compared to £41.4 in the CSFB Reference Case, a difference of .37p/kWh.
The inclusion of system costs does not alter the essential outcomes of the CSFB Reference Case. System integration costs raise overall portfolio generating cost by under 0.4p/kWh, although the new Mix S, which costs £42.60/mWh, is just 0.12 p/kWh higher than the CSFB Reference Case Target Mix, which costs £41.4/MWh.

The basic portfolio results remain largely unchanged from the CSFB Reference Case. The typical optimized mixes, Mix N and Mix S, contain 31% on-shore wind, as before, in spite of the fact that wind now costs more than new gas. The High-Cost Mix P is also unchanged from the CSFB Reference Case, with 31% onshore and 11% off-shore wind. On-shore wind is still limited by the arbitrary 31% constraint established for the analysis, suggesting that if the constraint were relaxed, cost-risk would improve. One stark difference is the case of offshore wind for Mix N. Here it appears that system charges reduce its optimal share to 2%, from it CSFB Reference Case level of 8%. The next section evaluated the effects of accelerating off-shore wind under the system charge assumptions.
Accelerated Off-shore Wind Deployment

The System-Charge Base Case, Mix S and Q contain no offshore wind. There exist infinite other mixes at these risk levels that do contain offshore wind. This sub-section explores the cost-risk of these possibilities by forcing the mix to include an arbitrary minimum off-shore wind share of 10%. The optimization now locates a new efficient frontier (minimum cost points) that contains at least 10% offshore wind. The target mix cost-risk remains unchanged from the System Charge Base Case.

![Portfolio Risk-Cost and Technology Shares](image)

**Figure 11: Optimized Results for Accelerated Offshore Wind Case**

Results-Accelerated Off-shore Wind

For the accelerated wind case, the cost of the target mix remains unchanged from the Base Case. Similarly, the Cost of Mix N remains unchanged even though it now contains 10% wind, versus 2% in the Base Case. For Mix S, costs now rise from 42.6 in the base case to 45.1, about a quarter pence per kWh. Generally, we conclude that accelerating offshore wind to 10% of the mix has a very minimal affect on the overall generating cost of the typical optimized mixes.
The effect of Higher Natural Gas and CO2 Prices: “Outlook Gas” Case

To this point, the analysis has assumed a *highly* cautious set of costs for on-shore and especially offshore wind. The assumed offshore wind cost, £76 per MWH, is nearly 50% higher than similar costs used in the Netherlands and elsewhere. In this section, we balance the cautious wind costs with higher assumed costs for natural gas, which are now taken as 40p/therm, the approximate outlook price for gas based on the cost of a 4-year gas forward. In addition, since CO2 costs are correlated with natural gas prices, we also raise carbon costs to €24/tonne. System Charges of £16/MWH for output remain unchanged.

![Figure 12: New Entrant Cost: Outlook Gas Case](image)

The optimized results for the Outlook Gas Case (Figure 13) are similar to previous results. In the typical optimal mixes, on-shore wind hits the arbitrary 31% constraint, again suggesting that greater wind concentrations would serve to further reduce cost and risk. The principal effect of the higher gas cost assumption is that off shore wind share in Mix N is 5%, compared to 2% in the Base Case.

The implication of this case is that is as follows. Expectation in the commodity markets is that 2010 gas prices will trend around levels of 40-p/therm. This is the indication from the 4-year forwards. If gas prices stay at these levels, then it would make sense for the Scottish Executive to aggressively pursue policy options that accelerate offshore wind deployment.
This can be seen from the Mix N (Figure 13), which contains 5% offshore plus 31% onshore wind at a cost equal to that of the target mix.

![Portfolio Risk-Cost and Technology Shares](image)

**Figure 13: Optimized Result: Outlook Gas and CO2 Case**

This idea is further illustrated by a closer examination of the two EF curves from the Accelerated Wind and the High Gas Price cases. This comparison is shown in Figure 14, which makes an important point. The EFs for the two cases are very similar. If high gas prices are sustained, a Scotland mix consisting of about 31% onshore wind and 10% offshore wind will generally outperform the NGC target mix, and will perform at least as well as other mixes with less wind.

![Figure 14: Optimal Solutions: Cases II and III](image)
4. Summary of Case Results and Conclusions

The portfolio analysis examines a number of cases. It begins with the CSFB Reference case, to which system integration charges are added to create the Base Case. The Base Case is next compared to an accelerated offshore wind case and an Outlook Gas case. The NGC target mix, which remains unchanged, contains 23% on-shore wind. In each case the typical optimized mixes contain 31% on-shore wind, indicating that they are constrained by the arbitrary resource bound established for this analysis. Further, a number of the cases contain additional shares of off-shore wind in Mix $N$. In each case the optimized mixes, which contain 50%–78% more wind than the target, exhibit better cost-risk. Constraining the wind share to reflect the effects of the Scottish Executive targets diminishes the generating portfolio’s cost-risk performance.

Figure 15 summarizes the major findings for the various cases. The NGC Target contains 23% wind in all cases. The Target Mix for each case is located by a small square of the same colour. Dashed lines connect the target mix with the Mixes $N$ and $S$. The percentages next to each Mix $N$ and $S$ indicate the total on and off-shore wind share.

The Reference Case, which uses CSFB new entrant costs that ignore system integration charges, establishes the baseline solutions. For this case, Mix $N$ contains 39% wind (8% off-shore) while Mix $S$ contains 31% wind. The Scotland generating system capacity is highly constrained, and this basic picture remains unchanged for the subsequent cases.

The System Charge Base Case applies the CSFB Reference costs, but adds a 16$/MWH charge to wind. While this increases the relative wind costs, the optimized solutions remain largely unchanged—most likely because our arbitrary 31% wind resource constraint already reduces the wind shares from their unconstrained optimal shares. The principal effect of the system charge therefore is to decrease the optimized offshore share in Mix $N$ to 2%. The Base Case is simply the CSFB Reference, with system integration charges incorporated. The Base Case therefore most likely better represents cost realities given today’s system architecture and protocols.

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14 If the constraint were lifted, it is likely that the Base Reference and Base Cases would both contain more than 31% wind, but the Base Case shares would be smaller.
Figure 15: Summary of Costs-Risk, Efficient Frontiers and Wind Shares

- **CSFB Reference**
- **System Charge Base Case**
- **Min. 10% Off-shore**
- **Outlook Gas**
- **18% Scottish Exec Target**

- **36% wind**
- **33%**
- **31%**
- **31% wind**
- **39%**
- **31% Wind**
- **Target Mix**
- **Target**
The Efficient frontier for the Outlook Gas Case is quite similar to the EF for the Minimum 10% Offshore Wind Case. This suggests that further deploying offshore wind may represent a no-regrets policy in Scotland. For the 10% Offshore Wind Case, typical optimized mixes contain about 40% wind, with 10% offshore wind. For the Outlook Gas Case, Mix $N$ contains 36% wind—about 3% more than for the Base Case.

Finally, Figure 15 shows the effects of constraining wind shares to a level more in keeping with the Scottish Executive’s targets. Given the existing 6% hydro share, the Executive’s 18% renewables target implies a 12% wind share. This target fails to exploit the risk-mitigation capabilities of wind and, as Figure 15 illustrates, forces the generating mix into a riskier and costlier region.

Conclusions: Implications for Scotland’s Capacity Planning

Today’s dynamic and uncertain energy environment requires portfolio-based techniques that reflect market risk and de-emphasize stand-alone generating costs. Mean-variance portfolio theory is well tested and ideally suited to evaluating national electricity strategies. It helps identify solutions that enhance energy diversity and security and are therefore considerably more robust than arbitrarily mixing technology alternatives.

Portfolio analysis reflects the cost inter-relationship (covariances) among generating alternatives, which is crucial for correctly estimating overall portfolio cost-risk. The analysis does not represent or advocate for a particular capacity expansion plan for Scotland. Rather, its purpose is to demonstrate that increasing the share of wind generally lowers overall generating costs, even if it believed that wind costs more than gas. The results generally suggest that the NGC 2010 mix, though it reflects a relatively significant 23% wind share, may not go far enough. Larger wind shares appear to better insulate the generating mix from systematic risk of gas (and coal) price movements, which have historically been quite correlated.

This report presents a series of optimized portfolio results for several scenarios, using a highly cautious set of cost estimates for wind and compares them to the NGC-2010 Scotland generating mix. The NGC mix includes no offshore wind. The optimized results indicate that without increasing cost or risk, onshore wind can be increased to at least 31% of electricity generation—half again as much as the NGC target and nearly 75% more than envisioned by the Scottish Executive’s 2010 targets. Even with a highly cautious cost of 76/MWH, (compared to gas at 30p/therm) offshore wind shares can rise to at least to as much as 10%, (2 GW of capacity) without increasing cost.

Moreover, if natural prices remain in the range of 40p/kWh, as futures prices indicate, a generating mix consisting of about 31% onshore and 10% offshore wind will generally outperform the NGC-2010 generating mix and will perform at least as well as other portfolios with less wind. Such a mix provides the basis for a no-regrets wind policy for Scotland.
Against this backdrop, the Scottish Executive 18% 2010 renewables targets may not be sufficiently aggressive. Indeed the analysis indicates that reducing wind shares from their optimized levels (31% onshore 5–10% offshore) significantly increases the cost and the risk of the Scottish mix.

In deregulated environments, investment decisions are made by individual power producers who evaluate only their own direct costs and risks, but do not reflect the effects their technologies may have on overall generating portfolio performance. Wind investors, for example, cannot capture the risk-mitigation benefits they produce for the overall portfolio, which leads to under-investment in wind relative to levels that may be more optimal from a customer or societal perspective. Similarly, some investors may prefer the risk menu offered by fuel-intensive technologies such as gas–CC turbines, which have low initial costs. Given sufficient market power, gas generators may be able to externalize fuel risks onto customers. In effect, these investors do not bear the full risk effects they impose onto the generating mix, which may lead to over-investment in gas relative to what is more optimal from a total portfolio perspective.

This analysis described in this report uses mean-variance portfolio (MVP) theory to evaluate the effects of wind on the Scottish generating mix. It does not represent or advocate for a particular capacity expansion plan. Rather, its purpose is to demonstrate that increasing the share of wind does not necessarily raise overall generating costs even if planners and policy makers believe that wind costs more than gas.

Today’s dynamic and uncertain energy environment requires portfolio-based planning procedures that accommodate market risk and de-emphasize stand-alone generating costs. Portfolio analysis reflects the cost inter-relationship (covariances) among generating alternatives. Though crucial for correctly estimating overall cost, electricity-planning models universally ignore this fundamental statistical relationship and instead resort to sensitivity analysis and other ill-suited techniques to deal with risk. Sensitivity analysis cannot replicate the important cost inter-relationships that dramatically affect estimated portfolio costs and risks (Awerbuch, 1993) and is not a substitute for portfolio-based approaches.

Mean-variance portfolio (MVP) theory is well tested and ideally suited to evaluating national electricity strategies.\(^{15}\) The MVP framework offers solutions that enhance energy diversity and security and are therefore considerably more robust than arbitrarily mixing technology alternatives. MVP suggests that the NGC Target Mix, though it envisions relatively significant wind shares, does not go far enough. Larger wind shares appear to better

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\(^{15}\) Other techniques have also been applied, e.g. A.C. Stirling [1996, 1994], develops maximum-diversity portfolios based on a considerably broader uncertainty spectrum. Though radically different in its approach, his diversity model yields qualitatively similar results.
insulate the generating mix from systematic risk of coal and gas price movements, which have historically been highly correlated.\footnote{Increasing use of contracts may mitigate this historical relationship by pricing each fuel more on the basis of its costs. However, history suggests that when shortages for a particular fuel occur, the cost of alternative fossil fuels rises.}

Given the high degree of uncertainty about future energy prices, the relative value of generating technologies must be determined not by evaluating alternative resources, but by evaluating alternative resource portfolios. Energy analysts and policy makers face a future that is technologically, institutionally and politically complex and uncertain. In this environment, MVP techniques help establish renewables targets and portfolio standards that make economic and policy sense [Jansen, 2004]. They also provide the analytic basis policy-makers need to devise efficient generating mixes that maximize security and sustainability. MVP analysis shows that contrary to widespread belief, attaining these objectives need not increase cost. In the case of Scotland, increasing the share of wind, even if it is believed to cost more on a stand-alone basis, reduces portfolio cost-risk and enhances energy security.
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